The Future of the Grid

Evolving to Meet America's Needs

Hosted By

ALSTOM

Western Region Workshop

Pre-read Materials

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WELCOME LETTER

Dear Workshop Participant,

Thank you for participating in the Gridwise Alliance Western Region's "The Future of the Grid" Workshop. Your input is critical because this workshop will not only help to develop the Western Region's stakeholder-driven vision for our future electrical grid but will also serve as the region's contribution to the broader national level vision.

The electrical grid – as an enabling technology – provides the foundation for America's economic success. Our digital economy, our national security, and each of our day-to-day lives are highly dependent on reliable, safe, and affordable electricity. The electricity industry is now in the midst of a major transformation that will likely continue for the next two decades. By having thoughtful, provocative conversations now, we can ensure electrical grid reliability and security are maintained, innovation encouraged, and economic growth fostered during this transition period.

Our goals for this workshop and those that follow are both broad and ambitious. We will debate and discuss many challenges facing the electric industry. To help utilize our time at the workshop efficiently, we have compiled this document to describe the scenarios we will be discussing as well as to provide a summary of relevant industry information. Please take a few minutes to familiarize yourself with these materials so we can have a richer, more informative, and productive workshop.

We look forward to hearing your view on these important issues and we are hopeful that the outcome of the workshop will provide significant direction and insights on the stakeholder's vision for the future.

Sincerely,

Becky Harrison

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INTRODUCTION

It is an exciting time in the electricity sector, as major changes transform the way we generate, deliver, and use electricity. There are changes being driven by both new policies and new technologies. Furthermore, the dynamics of the consumer's role in these changes and the need to maintain a secure electrical grid governed by prudent regulations are combining to create a healthy debate that will no doubt take years to play out.

Regardless of our ultimate generation resource mix or production method (i.e., large scale central plants versus smaller scale distributed plants), our electrical grid and its operation will always play a critical role in our future electricity infrastructure. In fact, the operation of our grid will become more and more complex even as it becomes more critical to the security of our nation's economy in a manner analogous to the ways the cellular network has enabled the world of smart phones and mobile applications.

Earlier this year, the Edison Electric Institute released a report titled *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* [1]. This brief report provides an excellent summary of the growing issues facing many utilities with pressures of decreasing revenue and providing real alternatives for consumers. We recognize that while these are issues face the industry in general, they have regional and local differences that are important to understand as we explore how best to modify policies and invest in technology development.

We recognize that without thoughtful debate and planning these changes could result in unintended consequences that hinder productivity and innovation. With this in mind, the GridWise Alliance (GWA) and the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (DOE OE) are partnering to facilitate a series of four regional workshops in late 2013 and 2014 to develop a stakeholder-driven vision of the future grid, including its capabilities and operational requirements. This series of workshops will culminate with an executive summit in mid-2014 in Washington, D.C. Our goal is to identify and characterize the needed technological capabilities, financial models, and the modifications to policies and regulations to support safe and reliable electricity delivery.

These regional workshops will bring together thought leaders from all stakeholder groups (utilities, regulators, state government officials, renewable energy providers, suppliers, and industry innovators) to develop the vision for the grid and grid operators in 2030. Each workshop is targeted to have approximately 60 participants to engage in a series of small, facilitated breakout discussions with their peers. The ideas from each workshop with be summarized in a brief document and provided to the participants.

The result of these efforts will inform national efforts at DOE, help guide an R&D agenda, and serve as a tool to educate all stakeholders including state and Federal policy makers and regulators. These efforts will help us develop a much better understanding of the issues that we must address to achieve the goal of an affordable, reliable, and resilient electrical system that will ensure both a vibrate national economy and protection of our national security.

WORKSHOP DISCUSSION SCENARIOS

WORKSHOP DISCUSSION SCENARIOS

Accurately characterizing what the operation of the U.S. electricity delivery system will be in 2030 is difficult if not impossible. However, in order to be prepared for the future, it is important to begin thinking and planning for it now. Individuals involved in the current operation of the grid are in the best position to understand the complexity and nuances of grid operations and how changing external factors could impact operations. There are a large number of factors from policy drivers, to customer expectations, to technological developments that will determine how the grid must function. To narrow and focus our discussion, the workshop will focus on five main scenarios. The scenarios were selected with the hope of stimulating your thinking to drive innovative ideas and possibilities while simultaneously grounding them in reality and what situations are likely today. The five scenarios are not exhaustive of all possible situations but rather have been developed to try to cover a wide range of the grid landscape while also accounting for possible regional uniqueness. During the workshop participants will be asked to engage in discussions on one of these scenarios.

SCENARIO 1: THE CHALLENGE OF BALANCING SUPPLY AND DEMAND AS GRID COMPLEXITY GROWS

Description

Today, transmission grid operators must ensure there is enough power generation both in terms of wattage and volt-amperes reactive (VARS) to service the load on their systems. To do so, the transmission grid operator continually adjusts the central generation. In some systems, they can also use a limited amount of demand response as another resource to keep the supply and load in balance. Today for residential demand response, the operator typically sends a signal to switches on customers' air conditioners, water heaters, and/or pool pumps to cut off the load completely or cycle off for a given percentage of time in an hour. This simple but effective mechanism allows the operator to ride through a few critical peaks as an alternative to providing additional generation. In the future, with increasing penetration of distributed energy resources, the distribution grid will have to be able manage two-way power flows and must be able to balance more complex supply and demand options.

The devices on the "customers' side" of the meter may include distributed generation; distributed storage; home energy management systems that can control various loads; appliances that can react to pricing signals; and options for charging or discharging electric vehicles. At the transmission level, utility scale generation will also be changing to include increasing penetration of non-dispatchable generation such as large-scale wind farms and other renewables as well as utility scale storage capabilities, all of which will require enhancements to existing balancing capabilities. This increasing dependence on devices at the "edge of the grid" will also require greater interaction between the distribution and transmission grid and grid operators to optimize the balancing of supply and demand functions.

Questions to Ponder

- What do these new balancing requirements mean to the role of the grid and the grid operator?
- What new demands will the increase in distributed energy resources create for the distribution grid and its operators?
- What new demands will increasing distributed and large non-dispatchable resources create for the transmission grid and its operators?
- What is the distribution grid operator's role versus the transmission grid operator's role?
- Will transmission operators need more visibility into the distribution grid?
- What new capabilities will be needed to perform this role? Are new tools/models/information needed?
- How will a shifting fuel mix (reduced coal, increased natural gas, increased renewables, etc.) drive or alter grid operational needs?
- How do current policies and regulation have to change to enable these new capabilities and roles?

- What are the financial implications of this transition? How do we ensure grid operators and owners are financially viable?
- What are the implications for the future workforce – both inside the utilities and third party providers?
- How must market structures evolve to handle new players?

SCENARIO 2: THE CHALLENGE OF INVOLVING CUSTOMERS AND THEIR ELECTRICAL LOADS IN GRID OPERATIONS

Description

Significant innovation is already occurring across all customer classes with smart devices now commonplace in many residences and businesses around the country. It's relatively safe to assume that by 2030 every device connected to the grid could be capable of communicating to the grid operator and receiving a control signal. Many of these will be purchased by consumers from various retail suppliers with the expectation that they will "plug and play" with grid operations. The challenge is to define an architecture and design that can optimize the loads and their responses in ways that maximize efficiency and minimize costs.

Currently customers are beginning to pay more attention to their unique requirements (such as high reliability, green energy, and/or least cost), and this focus tends to highlight those requirements that are not easily met by the current grid design and operation. Superstorm Sandy and other natural disasters have, for example, focused attention on discontinuities that occur for many customers when health, safety, and even life are threatened. Local generation tends to be the solution customers choose, but typically without consideration for their impact on grid operation when scaled from hundreds to tens of thousands of distributed scale sources.

Similarly, the push to reduce greenhouse gas and other pollution emissions typically associated with electricity has resulted in a significant increase in local clean generation (such as roof top solar photovoltaic systems), electrified transportation, and ultimately storage. By 2030, it is likely that local generation and the interaction with major and critical loads will drive operational strategies that are substantially different than current ones. The challenge will be to operate the grid with this diversity at the edge of the grid, incorporating complex economics with complex physical integration. Ancillary services will increasingly be met by controlling devices at the edge of the grid, thus creating challenges of synchronizing the operation of potentially millions of these devices.

Customers will be much more in the driver's seat in this future system with more options for how they react to the price of energy and services. Australia is already experiencing falling overall electricity demand at the same time the country is seeing higher peak demand. As the price of energy increases, customers are likely to make decisions that could drive this imbalance even higher.

Transactive energy is a term coined more than a decade ago to represent this complex interaction between the physics and economics at the edge of the grid. Grid operators in the Pacific Northwest in particular are developing this concept and experimenting with applying it in practice. It represents the type of concept that will be not only important but essential in the electrical grid of 2030.

Questions to Ponder

- What impact will increasing consumer participation mean to the operation of the grid? What new capabilities are needed?
- What will end customers who generate their own electricity (prosumers) expect from the grid and the grid operator?
- How will the consumer role change from what it is today?
- How does this change the role of the grid operator?
- What new role does the distribution grid operator need to play versus the transmission grid operator?
- What new capabilities will be needed to perform this new role?
- How must current policies and regulation change to enable this new capability and role?
- What are the financial implications of this transition?
- How will increasing energy prices impact the transition to distributed generation and storage?
- What are the risks of having the wrong pricing strategy?
- What are the implications for the future workforce – both inside the utilities and among third party providers?

SCENARIO 3: THE CHALLENGE OF HIGHER LOCAL RELIABILITY THROUGH MULTI-CUSTOMER MICROGRIDS

Description

Customers are becoming increasingly aware that the traditional "grid" electricity they've taken for granted is, in many cases, not meeting their needs. Whether customers want cleaner, more reliable, and better quality electricity or just "smarter" options, they are beginning to drive a new market for "non-grid" electricity technologies. These new customer-centric technologies are being developed and deployed at staggering rates and often without enough consideration for the impacts they might have on grid operations.

The design and operation of these "local grids" – or as they are commonly called *microgrids* – is still evolving with dozens of "beta" versions being built around the country. These new systems can be under the control of a single customer or serve multiple customers, and they will typically utilize the utility grid infrastructure as part of the local microgrid that can be "islanded" as desired. These systems will become more and more sophisticated in the near future resulting in mature markets by 2020 and beyond. Additional information on microgrids is provided later in this report.

David Crane, CEO of NRG Inc., is one of the industry's most vocal advocates these days for the rapid move to distributed electricity generation resources and the disruptive impact they will have on the traditional grid. NRG is currently testing several Stirling engine-based combined heating and power (CHP) devices for residential application. They plan to have units commercially available for sale in late 2014.

Whether it's Stirling engines, roof-top solar photovoltaic modules, fuel cells, batteries, or something else, it is clear that microgrids will evolve to be a dominate force in the operation of the grid by 2030 and beyond. The challenge for grid operators will be to create the appropriate interfaces with these systems to allow optimal operation of the grid, the microgrid(s), and both together.

Questions to Ponder

- What are the implications of this new balancing requirement to the role of the grid and the grid operator?
- What exactly is the distribution operator's role versus the transmission operator's role?
- What new capabilities will be needed to perform these roles?
- What will the "owners" of this microgrid expect?
- What will the customers served by the microgrid expect?
- How will the increase in microgrids impact transmission planning?
- How must current policies and regulation change to enable this new capability and roles?
- What are the financial implications of this transition?

- What are the implications for the future workforce – both inside the utilities and among third party providers?
- How will planning occur for these microgrids? How will it impact the grid operator role?
- How will increased microgrids impact infrastructure investments?
- Will new rate structures be needed?

SCENARIO 4: THE CHALLENGE OF TRANSITIONING CENTRAL GENERATION TO CLEAN ENERGY SOURCES—LARGE-SCALE WIND, SOLAR, AND GAS

Description

Across the U.S. and the globe we are seeing a transition of central generation from traditional fuel sources to cleaner fuel sources. This transition is being driven by policies, regulations, economics, and public sentiment. Various incentives and increasing market demand have driven down the price for wind and solar while new policies and regulations are driving up the price of coal, oil, and nuclear. Technological advances have resulted in cheap natural gas here in the U.S. Together, these are driving a transition in the US large-scale generation mix. This transition is also introducing new challenges and opportunities, bringing new participants into the market, and introducing new operating characteristics for the generation fleet.

This changing large-scale generation mix also brings increasing variability that the grid must accommodate and manage. This variability is resulting in having excess power at times as well as competing priorities for when the various generators should or must operate. In the Pacific Northwest, the combination of hydroelectric and wind generation has introduced the need to balance these competing priorities. To leverage fully these available resources, the grid operators must consider new ways to manage the load side of the energy value chain equation. At the same time, customers are taking more control of their energy usage. Many are lowering their overall demand for electricity through energy efficiency and changing behaviors or by installing rooftop solar installations, buying "smart appliances," and signing up for new third party services that can help them better manage their electricity usage.

These dynamics are changing the role of the grid and the grid operator going forward. They are also challenging traditional planning processes. In an industry where assets traditionally have a 30 year or better life span, these changes could result in overbuilding some asset capacity and underbuilding others.

Questions to Ponder

- Will these shifts to different generation fuels result in an increased regional approach to siting and leveraging future generation, and if so, what are the implications to the grid?
- What capability will be required of the grid to fully leverage non-dispatchable large generation sources such as wind?
- How does this change the role of the distribution grid and transmission grid operators?
- What role does the distribution grid operator need to play versus the transmission grid operator?
- How must current policies and regulation change to enable this new capability and role?

- What are the financial implications of this transition?
- What are the implications for the future workforce – both inside the utilities and among third party providers?
- What are the new tools/models/information needed to handle this transition?

SCENARIO 5: PLANNING FOR EMPOWERED CUSTOMERS

Description

In the past, for the majority of residential and small commercial electric customers there has been little to no choice in how they met their electric power needs. The electric utility industry has been a commodity business where much like the days when Henry Ford made his famous statement "People can have the Model T in any color – so long as it's black", electric customers were at the mercy of their power company. The industry mindset can even be seen in the fact that that we have referred to them as "rate payers" not "customers". In the future, grid owners and operators must change this mindset and gain a better understanding of customers ' needs, desires and ultimately their choices.

Technological innovations, new market structures and changing customer expectations are changing this long held view of end users of our product. Customers are now becoming empowered. Smart meters, distributed small scale generation options, smart appliances, home energy management systems, electric vehicles, and battery storage are some of the technology advances that are driving a paradigm shift with regards to electric customer choice. And customers are much more informed about what is possible – social media is expanding their "neighborhood" to allow them to compare experiences and options with others across the country and across the globe.

Policies are also playing a part in this evolution. Net metering rules that allow customers to get full retail credit for any power they produce from renewable sources and retail deregulations where new energy service providers can offer innovative rates are examples.

Prices are also having a significant impact on the choices customers make. As electricity prices rise and distributed generation cost decline, customers are looking at alternatives and options. It is now economically viable for customers in some areas to use rooftop solar to offset the energy they purchase from their provider. Energy efficiency is seen as a good investment by increasing numbers. Education is also starting to result in behavior changes that lower demand.

Looking out at 2030, it is not hard to imagine that electric customers will have a profound impact on the energy value chain and how it should be built and operated. As we look at the role of the future electric grid and the grid operator, consider the following questions.

Questions to Ponder

- How could this new dynamic of increasing customer expectations and choices impact the distribution grid?
- How could this new dynamic impact the transmission grid?
- How should grid operators plan for this new dynamic of customer empowerment and their associated increasing expectations?

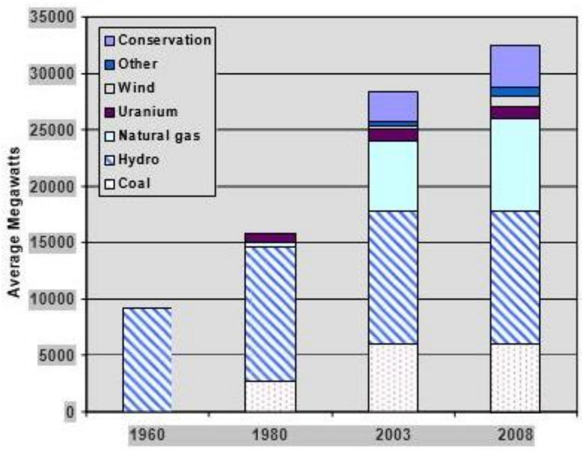
- Will customer owned battery storage be the killer app that directly competes against grid services?
- What are the financial implications for funding grid investments and on-going operations?
- How will market structures need to change?
- How should we plan for those customers that cannot or choose not to generate their own electricity to insure their cost for electricity stays reasonable?
- Does this impact the relationship between transmission and distribution?
- What impacts and expectations will retail service providers, who own the customers in deregulated retail markets, have on the grid and the grid operator?
- What new capabilities will grid operators and the grid needed to meet these new impacts and expectations?
- What new tools/models/information will grid operators need?
- How do current policies and regulation have to change to enable this new capability and role?
- What are the implications for the future workforce – both inside the utilities and third party providers?
- How will market structures need to evolve to handle new players?

BACKGROUND INFORMATION

WESTERN REGION CONDITIONS

The generation mix in Pacific Northwest includes coal, natural gas, hydroelectric, nuclear, as well as both distributed and centrally generated renewable resources such as wind, solar, geothermal and others **[2]**. Despite the prevalence of renewables in the region, a long-term reliability assessment conducted by the North American Electric Reliability Corporation (NERC) found that "Distributed generation, including rooftop solar and behind-the-meter generation, represents an insignificant portion of both the existing and planned resources." As seen in Figure 1 the current Pacific Northwest electricity generation fuel mix is dominated by hydroelectric, natural gas, and coal-fired generation. The power generated by each of these resources is 87,769 MW, 61,439 MW, and 35,069 MW, respectively **[3]**.

Figure 1. Historical Data on Power Generation



However, the generation landscape is likely to change significantly over the next 10 to 20 years. The Sixth Northwest Conservation and Electric Power Plan of the Northwest Power and Conservation Council ("Northwest Power Plan") states that increasing the development of renewable generation will be necessary to meet existing renewable portfolio standards that have been put in place by California, Oregon and Washington [2].

The Northwest Power Plan considers various scenarios in achieving reductions in carbon emissions including simply retiring about half the coal-fired plants versus instituting carbon pricing penalties. The report concludes there are advantages and disadvantages to both ways:

"… in order to reduce carbon emissions from the Northwest power system… the region would have to acquire about 5,900 average megawatts of efficiency and significantly reduce the use of existing coal-fired power plants. If conservation were not available to the region in the face of carbon-pricing risk, the probability of meeting carbon reduction targets would only be 36 percent. Phasing out about half of the existing coal plants would provide a more assured reduction of carbon emissions at a comparable expected cost without the carbon penalty included. There is no guarantee that coal retirement would be a substitute for carbon pricing, however. Fewer coal plants would need to be retired if the region also faced the risk of carbon penalties. But relying on response to carbon risk does not provide the same assurance of carbon reductions" [2].

For its part, the Bonneville Power Administration finds that "the direction of Federal climate change policy and energy legislation remains uncertain. California's plan to launch a cap and trade platform to put a price on greenhouse gas emissions in January 2013 is likely to affect electricity prices and the types of new generation developed in our region" [4].

As previously noted, almost all of the recent renewable development has been wind-based, and it is likely to be the primary source of renewable energy in the immediate future [2]. However, as the Bonneville Power Administration points out, power production from wind projects creates little dependable peak capacity and increases the need for significant balancing reserves to preserve reliability. They point out that ability of the Federal hydroelectric system to provide balancing reserves is finite and that access to non-Federal balancing resources is going to be necessary [4].

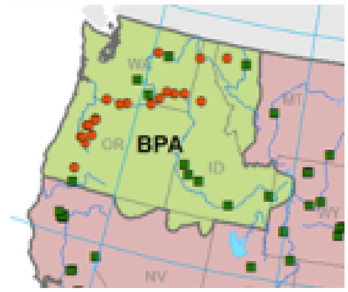


Figure 2. Service Area for Bonneville Power Administration

In the Pacific Northwest, the capacity of wind-power generating facilities reached more than 7,900 MW in 2012 and RPS standards in the region and California are projected to necessitate as much as 10,000 MW of renewables by 2020. Furthermore, the renewable resources developed to fulfill state RPS mandates will contribute an additional 4,500 MW. The continued growth of these resources will require the utility providers in the region to understand and manage the costs and risks that come with increased variability in the region's energy resource portfolio [4].

Example GHG emission reduction targets in three states:

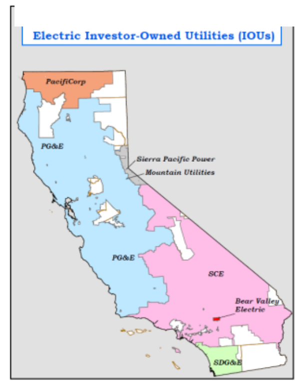
***California Cap-and-Trade**: California has committed to reducing GHG emissions to 1990 levels by 2020 (a reduction of approximately 30%) and an 80% reduction from 1990 levels by 2050. California has also launched a cap-and-trade system on power plant emissions that will affect electric power producers and industry, with the revenues generated directed towards funding renewable energy and energy efficiency programs. Combined with mitigation programs in other states, this may lead to a cumulative reduction in national greenhouse gas emissions by 2020.*

***Washington GHG Emissions**: In 2008 Washington passed E2SHB 2815. This bill put into law the state's GHG emissions reduction targets of 1990 levels by the year 2020, 25% below 1990 levels by 2035 and 50% below 1990 levels by 2050. Washington's strategies are outlined in the Interim Plan to Address Washington's Greenhouse Gas Emissions published in December, 2010. Washington favors a market-based system that sets a limit on GHG emissions and allows the market to determine strategies to reduce emissions at the lowest cost to the economy.*

***Oregon GHG Emissions Reduction Goals**: The Oregon State Legislature established GHG reduction goals of 10% below 1990 levels by 2020 and 75% by 2050. Significant investments in energy efficiency and conservation have allowed Oregon to reduce GHG emissions while maintaining a competitively low cost* *of energy. Oregon has also committed to making sure infrastructure investments account for climate risks* [5].

Washington, Oregon, and Idaho are serviced by the Bonneville Power Administration. Figure 2 shows the service area that Bonneville encompasses [6]. The Northwest Power Plan notes that Bonneville "occupies a unique, dual role in the region's utility system. On one hand it functions as a utility business, supplying energy, load-following, reserves, and transmission…On the other hand, in addition to its utility business functions, Bonneville is also a Federal agency, to which Congress entrusted defined public purposes." [2]The BPA has more than 15,000 miles (24,000 km) of electrical lines and 300 substations in the Pacific Northwest and controls approximately 75 percent of the high-voltage (230 kV and higher) transmission capacity in the region [7].

Figure 3. California IOUs by Region



California is serviced by 5 main investor owned utilities that operate in on a traditional utility model. The utilities are Bear Valley Electric Service (BVES), Pacific Gas and Electric Company (PG&E)**,** PacifiCorp, San Diego Gas & Electric (SDG&E) and California Edison (SCE). The California utility service areas are shown in Figure 3 [8].

LANDSCAPE OF THE INDUSTRY

Almost everything written about the electric power industry these days refers to change: changing customer demands, changing policies, changing technologies, and even changing business models. Such a dynamic landscape is difficult to characterize and impossible to capture in this brief document. Nevertheless, we attempt in this section to provide key highlights that provide some indication of the direction, speed, and magnitude of the changes that will influence the nature of grid operations in 2030 and beyond. The information provided here is not new, but is based on the most important and readily referenced documents we could find.

In the North American Electric Reliability Corporation (NERC) *2012 Long-Term Reliability Assessment* published earlier this year [3], NERC identified broad issues that are impacting the industry and its ability to maintain the reliability of the bulk power system at mandated levels. These findings shown in Appendix A represent a comprehensive look at grid reliability and do not necessarily reflect specific regional or local issues. While they do address a ten year view of the industry, they do not necessarily reflect the organic innovation taking place both in the utility industry and among customers.

CUSTOMER LOAD AND DEMAND PROJECTIONS

Projections for future electricity needs are being estimated by several organizations. Table 1 shows projections for 2035 electricity sales ranging from 4,421 billion kWh to 5,316 billion kWh with residential sales, the largest component in all but EVA's projections, increasing between 16 and 48% as compared to the 2011 baseline. Not shown in this table is the transportation sector. Because of improvements in fuel economy standards, transportation sector energy use is expected to stay constant through 2040. However, electricity sold to the transportation sector is expected to triple to 19 billion kWh in 2040 with increasing sales of electric plug-in LDVs [9] [10]. While small compared to these other areas, electric vehicles might be important at the local distributed level and thus are discussed further in the Electric Vehicles section.

Table 1. Comparison of 2035 Electricity Projections [9]

	2035 Projections in billion kilowatt-hours (kWh)[1]					
	2011 (baseline)	EIA (AEO2013)	IHGSI	INFORUM	NREL	EVA
Electricity Sales	3,725	4,421	5,316	4,406	4,824	4,923

[1] Projections were made by the Energy Information Administration (EIA), IHS Global Insight, Inc. (IHGSI), Interindustry Forecasting Project at the University of Maryland (INFORUM), National Renewable Energy Laboratory (NREL), and Energy Ventures Analysis (EVA).

Residential	1,424	1,661	2,001	1,718	*Not reported*	2,116
Commercial/ Other Use	1,326	1,618	1,983	1,710	*Not reported*	2,292
Industrial	976	1,142	1,332	978	*Not reported*	515

Table 2 shows projections for 2035 electricity prices ranging from 10.1 to 11.9 cents per kWh with the highest prices occurring in the residential sector.

Table 2. Comparison of 2035 Electricity End-Use Prices [9]

	2035 Electricity Prices in 2011 cents per kWh[1]				
	2011 (baseline)	**EIA (AEO 2013)**	**IHGSI**	**INFORUM**	**NREL**
Average price	9.9	10.1	11.9	10.5	11.7
Residential	11.7	12.1	14.1	12.2	*Not reported*
Commercial	10.2	10.1	12.3	10.6	*Not reported*
Industrial	6.8	7.1	8.1	7.1	*Not reported*

EIA projects average electricity demand per household to decline by 6% by 2040 based on less consumption from lighting, PCs, laundry, and refrigeration and increased consumption from HVACs, TVs and other devices [9] [10]. For comparison, the ACEEE study projects a 2% decrease in residential energy use by 2050 with savings coming from heating and lighting [11].

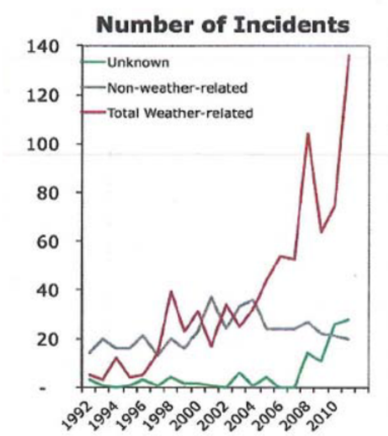
VERY LARGE SCALE WEATHER EVENTS

On October 29, 2012, Hurricane ("Superstorm") Sandy made landfall in southern New Jersey. Sandy pummeled the most densely populated region of the United States for an estimated damage totaled US $65 billion and left tens of millions of people without electricity for days or even weeks [12]. Recovery in the affected area continues more than a year later.

In the last two years there have been at least six very large scale events (VLSEs) in the U.S. including floods, windstorms, snowstorms, hurricanes, and prolonged droughts that trigger wildfires. These VLSEs are summarized in Figure 4. Power delivery systems are vulnerable to these events and data suggests that outages from weather-related events are on the rise.

These outages have real cost implications to utilities and consumers. Various studies have concluded that storm-related power outages cost the U.S. economy between $20 billion and $55 billion in a typical year. Depending on the outage duration the interruption could cost an industrial consumer over $4,000 [13]. The true impact on customers is difficult to measure and includes not only inconvenience but often threats to safety and health.

Figure 4. Weather-Related Power Outages



2011-2012 Extreme Events and Reported Customers Affected by Power Outages

Event	Date	Region	Customers Affected*
Superstorm Sandy	October 2012	Northeast	8.1M
"Derecho"	July 2012	Mid Atlantic	4.2M
Early Season Snow	October 2011	New England	3.0M
Hurricane Irene	August 2011	Mid Atlantic	3.2M
Western Wildfires	July 2012	California, Colorado	2.0M
Windstorm	November 2011	Southern California	0.4M

* Adopted from the Energy Information Administration.

Average Cost of a Power Interruption in the U.S.

Duration of Interruption	Residential	Commercial	Industrial
Momentary	$2.64	$733	$2,294
1 Hour	$3.27	$1,074	$3,943
Sustained Interruption*	$3.62	$1,293	$5,124

*The mean duration of a sustained interruption is 106 minutes.

Sources:
Weather-Related Power Outages and Electric System Resiliency.
The Gridwise Alliance. Lessons Learned from Superstorm Sandy and Other Extreme Events. June 2013.

Since Superstorm Sandy, much more attention is being given to reliability by local leaders, who are looking at a variety of options for local generation to address the most critical loads. In these cases cost becomes less important, and investments are being made in distributed power systems where standard economic arguments breakdown. Table 3 shows the variety of causes for outages including weather-related and other causes and the estimated total impact for each cause.

Table 3. Source and Size of Power Outages

		% of events	Mean size in MW	Mean size in customers
Weather Related Outages	Earthquake	0.8	1,408	375,900
	Tornado	2.8	367	115,439
	Hurricane/tropical storm	4.2	1,309	782,695
	Ice storm	5.0	1,152	343,448
	Lightning	11.3	270	70,944
	Wind/rain	14.8	793	185,199
	Other cold weather	5.5	542	150,255
	Fire	5.2	431	111,244
Other causes of outages	Intentional attack	1.6	340	24,572
	Supply shortage	5.3	341	138,957
	Other external cause	4.8	710	246,071
	Equipment failure	29.7	379	57,140
	Operator error	10.1	489	105,322
	Voltage reduction	7.7	153	212,900
	Volunteer reduction	5.9	190	134,543

CENTRAL AND DISTRIBUTED POWER GENERATION & ENERGY STORAGE

Technological advancements and policies are moving the U.S. generation mix away from coal and towards cleaner technologies such as natural gas, wind, and solar. The variability of wind and solar generation presents more complex control and economic scenarios for grid operators. Energy storage systems are being added to reduce the impact of supply variability and peak demand on transmission and distribution. While providing value they are another component in the system that needs to be monitored, controlled, and optimized. Smaller scale distributed power generation is becoming more economical and widespread, especially when it provides additional features such as high reliability.

Coal

The National Energy Technology Laboratory (NETL) tracks the development of new coal plants and has found that actual capacity of completed plants has been significantly less than proposed capacity. NETL's 2002 report listed 11,455 MW of proposed capacity for the year 2005 but only 329 MW were actually constructed. In 2011 1,599 MW of new capacity was announced and 2,890 MW were canceled. Combined capacity of plants scheduled for retirement by 2020 is 24.7 GW or 7% of the total U.S. coal generation capacity [14].

There are several projections on coal's viability as a generation source over the intermediate and long-term, and they make differing predictions. NERC showed coal's contribution to be approximately 30% in 2012 and projects its share of the market will drop to under 27% by 2022 based on 16GW of capacity retirement [3]. EIA's reference case shows coal-fired plants as the largest source of electricity generation in 2011 at 42% with its market share declining to 35% in 2040. Other EIA scenarios show coal-fired generation could be between 28% and 40% by 2040 [15]. EIA also projects that by 2040, 15% of the coal plants active in 2011 will be retired while only 3% of new generation capacity added will be from coal. This is due to Federal and state environmental regulations and uncertainty about future limits on GHG emissions [9] [10]. One example of where regulations are affecting coal generation is at the Tennessee Valley Authority (TVA). In 2010 the TVA entered into consent agreements with the U.S. Environmental Protection Agency, four states, and several environmental groups over the pollution from its 11 coal-fired power plants. TVA is in the process of retiring 30% of its coal fleet and evaluating the compliance cost for much of the rest [16]. Economic decisions based on environmental regulations, life of the plants, and presently inexpensive natural gas are contributing to the shifting capacity mix. Large power plants have high capital costs that are recuperated over the life of the plant, typically 20 or more years. Once coal-fired generation is replaced, it is unlikely that utilities will switch back. While newer generation technologies are cleaner, their capital and operational costs will be different, and utilities will need to address these issues in their business models.

Table 4. Coal Generation Scheduled for Retirement

Region	Retirement Date	Capacity Scheduled for Retirement [3]
NPCC – New England Assessment Area	Being considered	6 GW
NPCC – New York Assessment Area	Confirmed retired	1.2 GW
Ontario	2014	3.4 GW
PJM	2015	12.7 GW

Natural Gas

There has been a surge in production of natural gas in the U.S. due to the shale revolution bringing down prices for this fuel. Low natural gas prices and tightened pollution emissions requirements will create more demand for natural gas from the power sector [17].

There are several projections on natural gas as an electricity generation source. The Joint Institute for Strategic Energy Analysis (JISEA) studied natural gas in the energy sector and in their "Baseline – Mid-EUR" case projected natural gas combined-cycle and natural gas combustion-turbine capacities nearly doubling from 2010 to 2050 [18]. NERC showed natural gas generation to be 38.5% in 2012 and projects its share of the market will increase to 39.7% by 2022 based on 32 GW of capacity additions, although conception projections show an additional 68 GW [3]. EIA shows natural gas generation increasing its market share from 24% in 2011 to 30% in 2040 with natural gas-fired plants accounting for 63% of capacity additions during that period. Inexpensive natural gas makes existing natural gas plants more competitive with coal and lower capital costs makes natural gas-fired plants a viable choice for new generation capacity [15].

Forecasts of the future price of natural gas vary significantly. To hedge against increasing natural gas prices many utilities lock in fuel prices from suppliers. Should natural gas prices increase in the future the utilities will typically pass those costs along to consumers with a potentially major impact on the cost of their electricity.

Wind

In the last five years, there has been a surge in wind power deployments across consumer, industrial, and commercial sectors in the U.S. In 2012 cumulative land-based wind deployment was 60 GW as compared to 12 GW five years earlier. In 2012, wind deployment accounted for 43% of new electrical generation capacity in the U.S., the most of any generation technology. Additionally, the combined potential of land-based and off-shore wind is about 140 quads (quadrillion BTUs), which is 10 times U.S. electricity consumption today [19].

The success of wind deployments can be attributed to a variety of factors. These include the increase in turbine size which lowers the cost; the larger production volumes also helps to lower costs; production tax credits; and the improved capacity factor of plants from sophisticated operators, which increase the time plants are operational and thus producing revenues [19].

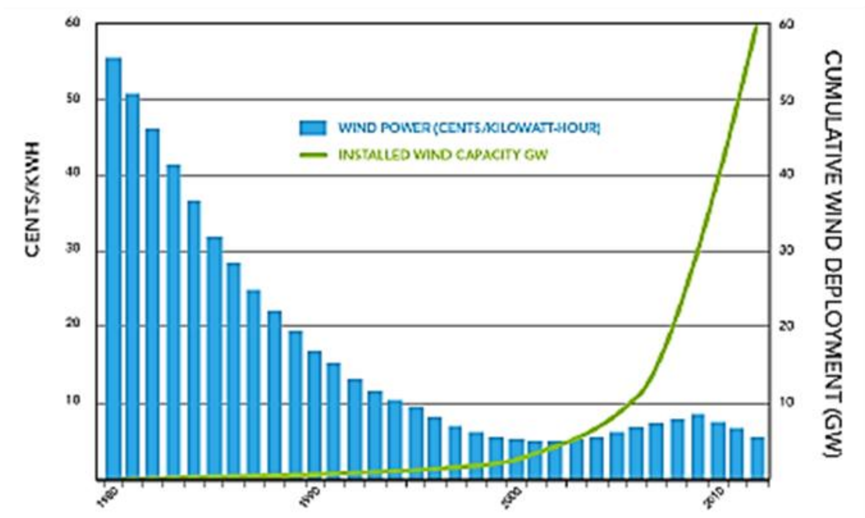
Looking ahead, DOE estimates that as much as 20% of projected U.S. electricity demand could be met by wind power by 2030 given policy support and continued technological improvements [20]. Although wind represents at present only 3.5% of the total electricity market, it is growing rapidly and regionally where the resource is abundant. For this reason, wind power is a poised to be disruptive to other power generation technologies. Integration studies such as *Western Wind and Solar Integration Study* and the *Eastern Renewable Generation Integration Study* are being completed to examine the impact large penetrations of variable generation sources will have on the electrical grid, and the development of planning and operations tools for flexibility and stability of the electrical grid [21] [22].

Figure 5 provides an overview of land-based wind energy assets in the United States including a time-series chart of the deployment (installed capacity in GW) and cost (in kWh) and a bar chart of new capacity additions in 2012.

There has been tremendous growth in wind energy outside the United States, especially in Europe. By the end of 2012, Europe had 110 GW of wind capacity on the grid [23]. Germany is home to over 21,500 wind turbines, a fact that has posed some interesting challenges for the country. When generation exceeds demand and energy storage is not feasible, generation must be shed. However, German energy laws stipulate that non-green power generation must be shed first, lowering the capacity factor and revenues for those plants. Another challenge has been the variable nature and high concentration of wind on the electrical grid. This has resulted in large changes in capacity requiring new tools and methods for system operations to improve flexibility and maintain network stability [24].

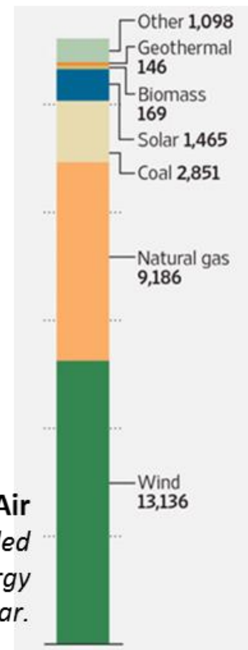
Figure 5. Wind Power Deployment

Deployment and Cost for U.S. Land-Based Wind



Source: The Department of Energy

New Capacity in Megawatts



Change in the Air

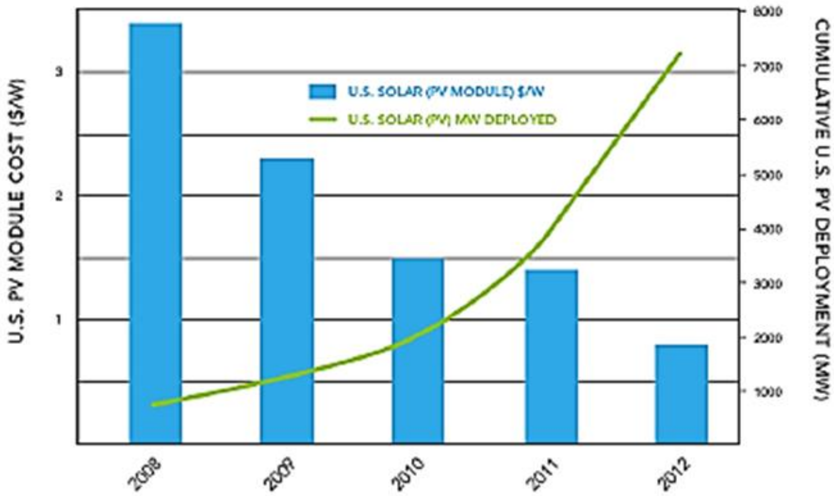
New generating capacity in the U.S. has included increasingly significant amounts of renewable energy sources, with wind surpassing natural gas last year.

Source: The Wall Street Journal

Solar

Solar is another renewable power generation technology that has made tremendous strides in recent years. As shown in Figure 6, in 2012 cumulative solar photovoltaic (PV) deployment was 7.3 GW, 10 times the deployment capacity of 2008. The EIA *Annual Energy Outlook* projects commercial PV capacity increasing between 6.5 and 7.4 percent annually through 2040 depending on various policy scenarios [15]. As with wind, solar represents a small portion of total electricity market, but it is growing rapidly and regionally where the resource is abundant. For this reason, it too can be both disruptive to other power generation technologies and pose challenges to the electrical grid.

Figure 6. U.S. Deployment and Cost for Solar PV Modules [19]



Solar deployment costs are comprised of the PV module and any inverters or batteries (i.e., equipment costs) and the so-called "soft costs" for permitting and installation. The drop in cost for a PV module is partly responsible for the dramatic increase in deployment. As Figure 6 further shows, PV module costs since 2008 have dropped by a factor of four to a present price of about $0.80/Watt. Soft costs in the U.S. are still high, about $3.34/W or approximately five times those of Germany. However, utility incentives, new financing options, and the current 30% Federal investment tax credit (scheduled to revert to 10% in 2017) have helped this technology achieve cost parity with electrical generation from gas, coal, and oil in many parts of the U.S. and put this technology within reach for the average homeowner or business [15] [19]. By 2030 local solar projects likely will be of sufficient scale to impact the operations of many local utilities. There are several large examples of distributed solar generation coming on-line in the U.S. The retail giant Walmart has installed solar PV modules on about 200 of its ~100,000 square foot stores delivering over 71 million kilowatt hours of energy annually. With about 4,500 stores in the U.S., and a goal of being served by 100% renewable energy, this could be a significant impact on the electrical grid [25] [26]. Figure 7 shows one such Walmart store with a large rooftop array of solar PV modules.

Figure 7. Distributed Solar on Walmart Store [26]

In Arizona roughly 500 new rooftop solar installations are completed each month. The Arizona Public Service (APS) has 20,000 homes in its territory with solar PV modules. Residential systems are generally on the order of 7-kW, resulting in a reduction of about two-thirds in the electrical utility bills for these houses. However, Arizona utilities argued that with the net metering practice, these homeowners were unfairly benefiting from the electrical grid's 24/7 power supply without paying for the maintenance costs for power plants and transmission lines. This past November, the Arizona Corporation Commission voted to add a monthly fee of $0.70/kW to the bills of all customers that install new solar systems. In other states, utilities have the same argument so this Arizona vote may create momentum to levy a similar fee in other states [27].

Europe experiences with integrating solar energy could benefit the U.S. By the end of 2012, Europe had 70 GW of solar capacity on the grid with 22.3 GW in Germany [23]. As with other renewable resources, solar generation is variable and in February 2013, Germany experienced a large positive system imbalance due to this variability. On this day there was quite a bit of snow on the PV modules that did not melt as estimated, which resulted in the system imbalance and an activation of reserves. Forecasting accuracy of solar generation will be increasingly important as more PV modules are installed [23].

Other Renewables

While wind and solar energy will tend to dominate in the next decade and beyond, other renewable resources will also have an impact. The EIA *Annual Energy Outlook* shows renewable generating capacity accounts for nearly one-fifth of total generating capacity in 2040 [15]. NREL's Renewable Electricity Futures Study concluded that a combination of a flexible electric system with today's commercially-available renewable electricity generation technologies can supply 80% of total U.S. electricity generation by 2050 [28].

Geothermal resources are found primarily in the American West and Southwest. The technology is emerging still but the potential for this resource is about 500 GW according to NREL. Hydroelectric ("hydropower") is already a primary source of energy in the Pacific Northwest. NREL estimates the U.S.

hydropower potential is 152 – 228 GW. Biopower is available in many regions and with an increase in energy crops and harvesting technologies in the future, NREL estimated a corresponding 100 GW of dedicated biopower capacity [28]. EIA's study projects much smaller amounts of geothermal (5 GW) and biopower (7 GW) plants entering operation. While these numbers are much less than wind and solar, they nevertheless represent a doubling in biopower capacity and a tripling in geothermal capacity from 2010 to 2040 [15].

Appliance-size fuel cells that provide both heat and power are just emerging today, but they may very well be common place in 2030 and beyond. These systems will decrease vulnerability associated with electrical grid outages by generating their own electricity for users with a system nearly impervious to hurricanes, thunderstorms, and similar dangers, while simultaneously helping the environment.

Redox Power Systems is working on a solid oxide fuel cell for residential applications that is 1/10th the size and cost of commercial units today with a nameplate capacity of 25 kW. Figure 8 shows a picture of such a residential fuel cell design. The system uses natural gas fuel to electrochemically convert methane to electricity. The goal is to generate onsite power and, optionally, off the grid at a price competitive with current energy sources [29].

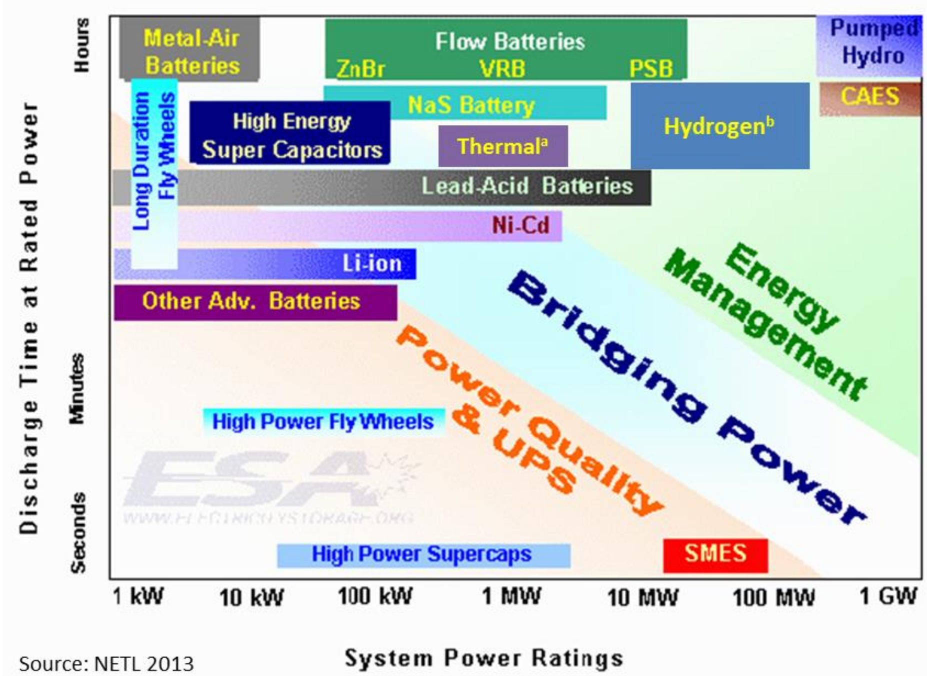
Figure 8. Redox Power Systems Residential Fuel Cell Design [29]

Energy Storage

Today's grid operator manages most fluctuations on the electrical grid by adjusting generation to maintain reliability and to adhere to strict conventions on voltage and frequency. In the future, clean variable generation such as wind and solar will have significantly increased, and policies are already in place or underway in most states to give them preference in meeting demand needs. Given the increased variability, energy storage technologies may provide flexible solutions throughout the electricity value chain.

Energy storage systems are designed with different energy densities, response times, time of operation, and power depending on the target application. The primary issues energy storage systems address are energy management, bridging power, and power quality. There are several technologies available that perform these energy storage functions from pumped hydro, which is a fairly mature technology, to capacitors and flywheels, which are only feasible in niche markets today. Figure 9 shows the discharge time for different types of energy storage systems (i.e., different system power ratings) and the primary issues that each type addresses.

Figure 9. Power Ratings and Discharge Times for Energy Storage Technologies



Source: NETL 2013
a. Source: Sopogy 2013.
b. Source: NREL 2010.
CAES = compressed air energy storage; Li-ion = lithium-ion; Ni-Cd = nickel cadmium; NaS = sodium sulfur; PSB = polysulfide bromide; SMES = superconducting magnetic energy storage; VRB = vanadium redox battery; ZnBr = zinc bromide

There are several examples of these technologies already deployed within the grid. Sodium sulfur (NaS) batteries have been in commercial use for over 10 years at the megawatt scale with over 300 MW installed globally. On the consumer side thermal energy storage systems are being used for bridging power applications and to help shave peak demand. Thermal storage uses off-peak electricity to store cooling energy or heat energy, then during peak demand uses that energy to meet power needs. The fashion retail store Nordstrom at the Ala Moana Center in Honolulu uses this technology to produce 43 tons of ice every night which helps cool the 210,000 square foot store during the day. As a result, the three-story store uses about half the electricity of a similarly sized retailer during daytime hours [30].

Energy storage is gaining state support. California now has a mandate for increasing energy storage requiring that the state's investor-owned utilities must begin buying a combined 200 MW of energy storage technology by 2014 and reaching 1,325 MW by the end of 2020. This recent decision was made in accordance with state law AB 2514, which was passed in 2010 and calls for the integration of renewable energy and the reduction of greenhouse gas emissions of 80% below 1990 levels by 2050 [31]. Figure 10 shows a rooftop thermal energy storage system.

Figure 10. Rooftop Thermal Energy Storage [30]

POLICY TRENDS

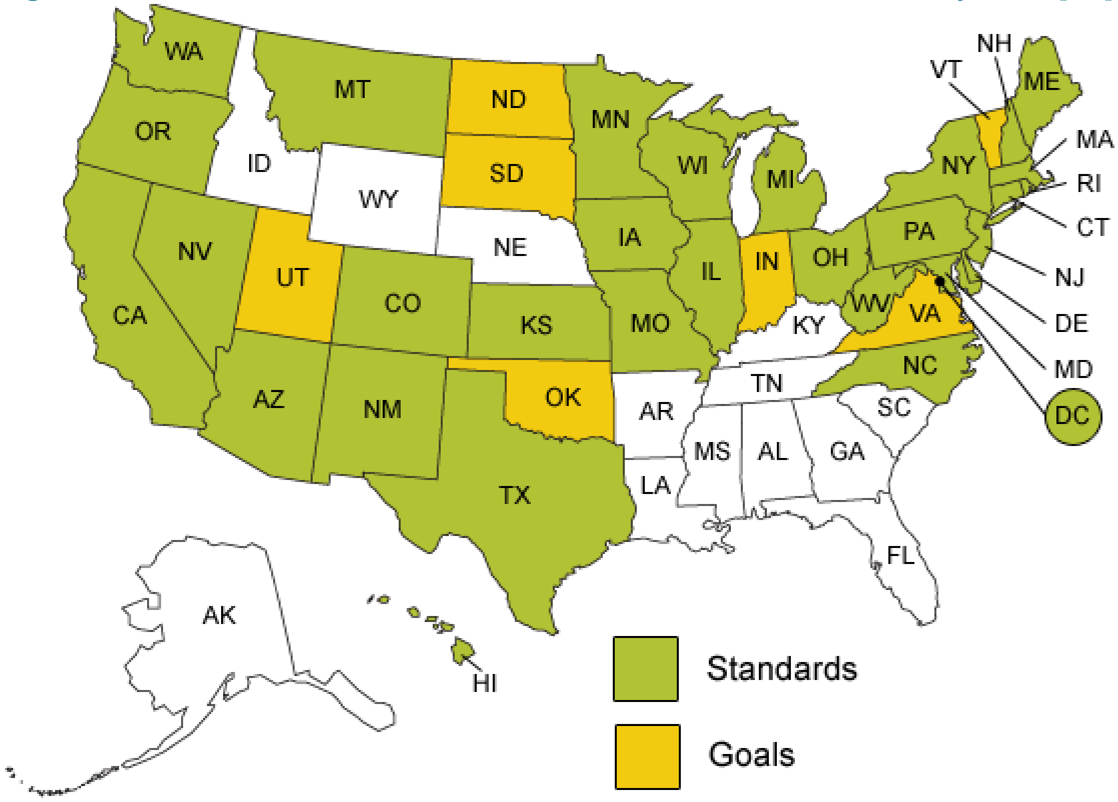
Federal, state, and local policies are all having an impact on the changes taking place to the grid. This section highlights the most important developments and trends in these new policies. While the shifting US political landscape will certainly affect the speed of policy changes, it is unlikely to significantly alter their fundamental direction.

Renewable Portfolio Standards

States with renewable portfolio standard (RPS) policies have seen an increase in the amount of electricity generated from eligible renewable resources. As of January 2012 the 30 U.S. States plus the District of Columbia highlighted in the map in Figure 11 had implemented RPS policies with legally mandated standards despite the lack of a national-level RPS program. Figure 11 also shows the seven U.S. States that have implemented RPS goals that reflect desired rather than legally mandated targets.

A large range of policies are considered to be under the RPS umbrella. RPS's vary widely in terms of program structure, enforcement mechanisms, size, and application, but they all have some common features. First, most RPS's sets a minimum requirement for the share of electricity to be supplied from designated renewable energy resources by a certain date/year. Second many state policies have a renewable electricity credit (REC) trading system structured to minimize the costs of compliance [32].

Figure 11. States with Renewable Portfolio Standards as of January 2012 [32]



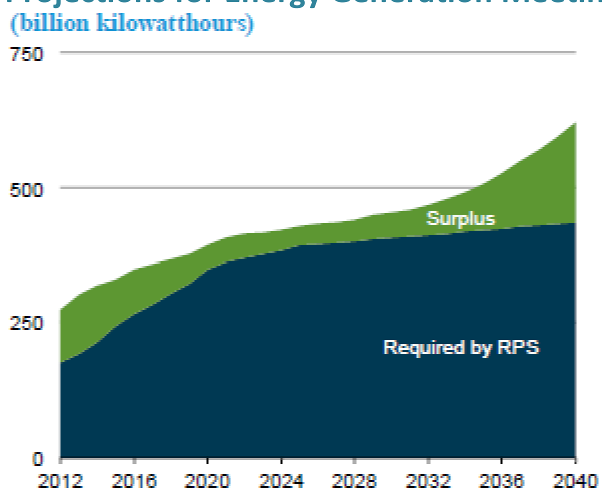
The policies under the RPS umbrella include solar and distributed generation provisions, property tax incentives for renewable, sales tax incentives, tax credits, rebates, and the incorporation of public benefit funds. Table 5 shows a list of these policies and their adoption levels across the U.S. Because some states have more than one mandated policy, the numbers are greater than the 30 shown in Figure 11.

Table 5. Summary of States with Financial Incentives Promoting Renewable Energy

Financial Incentives and Regulatory Policies in effect promoting renewable energy within the U.S. [33]			
Policy	# of States	D.C.	# of territories
Renewable Portfolio Goals	7		2
RPS with Solar and/or Distributed Generation provisions	16	Yes	
Property Tax Incentives	38	Yes	1
Public Benefits Funds	15	Yes	1
Rebates for Renewables	16	Yes	2
Sales Tax Incentives for Renewables	28		1
Tax Credits for Renewables	24		

At present, most states are meeting or exceeding their required levels of renewable generation based on qualified generation. This is partially due to expiring Federal incentives and cost reductions in wind and solar energy. Most RPS targets are tied to retail electricity sales. With relatively slow growth in electricity sales throughout most of the country, the renewable generation that has entered service recently has gone farther toward meeting proportionally lower targets for absolute amounts of energy (that is, for kilowatt-hours of energy, as opposed to energy as a percentage of sales) [15]. Figure 12 shows projections for energy generation meeting RPS targets through 2040, and it includes surplus energy as well as the amount required by the RPS.

Figure 12. Projections for Energy Generation Meeting RPS [15]



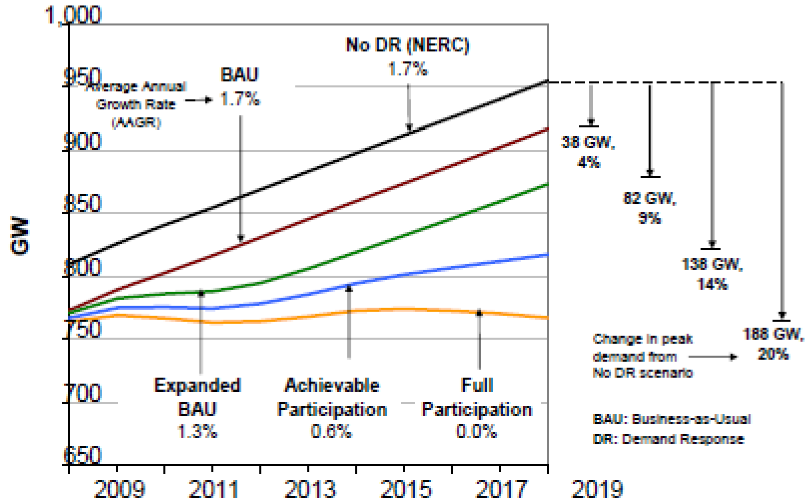
At the same time, even states without RPS policies are seeing significant increases in renewable generation over the past few years. These are a result of Federal incentives, state programs, and market conditions [32]. Based on the adoption rate of RPS the majority of the country is driving towards a minimum share of electricity to be supplied from renewable energy even without a national-level RPS program. As Figure 12 suggests, the projected amount of renewable generation required and achieved indicates that RPS targets will be exceeded. The grid will need to accommodate this additional renewable energy, as a result it will be necessary to forecast and communicate with these generation resources at different places on the grid.

Energy Efficiency and Demand Response Policies

Demand response encompasses a range of incentive mechanisms aimed at reducing customers' demands for electricity. These mechanisms can come in the form of price increases, incentive payments, dynamic pricing plans, and other strategies used to change the consumption patterns of end-users. Although generally aimed at reducing loads at peak demand, demand response can include actions that change any part of a utility's load profile.

A 2009 FERC study of demand response potential predicted varying levels of reduction in peak demand based on a number of different scenarios [34]. Figure 13 shows various a peak demand forecasts under the various scenarios presented in the FERC study projected running through 2018.

Figure 13. U.S. Peak Demand Forecast by Scenario [34]



If existing demand response policies were to continue, shown on the graph in Figure 11 as the "Business-as-Usual (BUA)" scenario, the U.S. could expect to see a 38 GW, or 4%, reduction in peak demand from the base case by 2019. By contrast, assuming a nationwide adoption of demand response programs where dynamic pricing is the norm, this model indicates a 188 GW, or 20% reduction in peak demand by 2019. This would not only keep pace with the annual growth rate, but it would also reduce the peak load from its starting point in 2009. This shows that effective demand response policies can have significant impacts on the nation's energy consumption and prices as well as saving utilities and customers substantial amounts of money.

Demand response is being encouraged by FERC through its National Action Plan on Demand Response, by Pacific Gas & Electric's InterAct tool, and a host of other national, state, and local actions. Legislative plans have been set in motion in several states that put forth goals for reduction of peak demand. For example, the Michigan Public Service Commission's *Michigan's 21st Century Energy Plan* and the State of New Jersey's Board of Public Utilities' *Energy Master Plan* both call on utilities to employ demand response practices. In 2009, legislation was passed in both Maryland and Colorado that set goals for energy consumption and peak demand reduction with the latter allowing cooperatively-owned utilities to set inclining block rates for residential customers [35]. This means that the more energy a household uses, the higher its per kilowatt hour cost, thus incentivizing the household to reduce its consumption. These actions help lower the overall demand for electricity, which may help counter the need for upgrades to transmission and distribution infrastructure due to additional loads entering into the grid.

Oftentimes states' demand response actions take the shape of retail programs, some of which may not require new enabling technologies such as smart meters. This was the case in Arizona, where its two major utilities offered time-of-use (TOU) pricing that attracted 30 to 40% of the residential market without requiring new equipment be installed in most cases.

California has had demand response regulations in place for quite some time including TOU pricing since 1978. These policies have contributed to the fact that the state's energy usage has remained constant for 30 years despite the overall increase for the U.S. as a whole [35]. In addition, California's Energy Action Plan has gained recognition for deploying advanced metering initiatives and dynamic pricing. In what was the country's first dynamic pricing pilot, California investigated adjusting rates to reflect the changing demand and account for peak loads for 2,500 customers. The program was considered a success, as it provided valuable data about customers' willingness to participate in a demand response program, and many customers elected to keep the experimental pricing scheme.

Building Requirements

Building requirements for private property are largely set on a state by state basis. The only major Federal rating program relating to building efficiency is the Energy Star program which is limited to commercial and industrial buildings and is voluntary in nature. In the government sector there are guidelines that require U.S. General Services Administration (GSA) building construction to meet Leadership in Energy and Engineering Design (LEED) Standards [36]. LEED is a third party certification program and the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. There are over 14,000 building certifications in the U.S. with the level of certifications increasing 4.5 times in the last five years [37].

Additionally Executive Order 13514, "Federal Leadership in Environmental, Energy and Economic Performance" signed by President Obama on October 5, 2009, instructs the Department of Defense to require all new construction be net-zero energy by 2030 [36], and the National Defense Authorization Act of 2007 requires that Department of Defense facilities source 25% of their energy from renewables by 2025 [38].

California is often a leader in environmental and energy policy. In 2007, the California Energy Commission released its Integrated Energy Policy Report (IPER). The IPER recommended that all new building construction should achieve net-zero energy by 2020 for residential buildings and by 2030 for commercial and industrial buildings. These recommendations are now in the process of incorporation into California's Building Energy Efficiency Standards which were updated in 2013 and are set to take effect January 1, 2014 [39].

These building requirements and initiatives revolve around the creation of high efficiency residential, commercial, and industrial buildings. They also include some renewable energy generation either onsite or to be purchased through an agreement with local utility providers. The renewable requirements and the possibility of onsite generation greatly affect the performance characteristics of the electrical grid and will need to be taken into account by grid operators in order to maintain grid stability.

Climate Action Plan

In June of 2013 President Obama put forth a broad based plan known as the Climate Action Plan to cut carbon pollution that is associated with human-induced global climate change and adversely affects public health. The plan consists of a variety of executive actions focused on the following:

- Cutting carbon pollution;
- Preparing the U.S. for the impacts of climate change; and
- Leading international efforts to address global climate change;

These actions will have a direct implication on power generation, grid modernization efforts, and consumer demand. One such action directs the Department of Interior to permit renewables projects (such as wind and solar) on public lands by 2020 to power more than 6 million homes, thereby impacting where and how power is generated on the electrical grid. Another action supports grid modernization by directing agencies to support local climate-resilient investment by removing barriers or counterproductive policies and by modernizing programs. Lastly, by expanding the President's Better Buildings Challenge to help commercial, industrial, and multi-family buildings become at least 20% more energy efficient by 2020, the Climate Action Plan attempts to lower the demand for electricity, which would directly impact the market size for the electrical grid.

Federal Smart Grid Legislation

Increasingly over the past decade Congress has taken a serious interest in electrical grid issues by passing various laws to address it. In 2007 the Energy Independence and Security Act (EISA) included Title XIII that is specific to the smart grid. Often overlooked in Title XIII is an opening paragraph stating that "it is the policy of the United States to support the modernizations of the Nation's electricity transmission and distribution system…." Title XIII goes on to define 10 key features of a modern electrical grid system that include things such as dynamic optimization of grid operations, integration of distributed resources, integration of smart consumer devices, etc. Title XIII also provides for demonstration projects, interoperability, the Smart Grid Task Force, and Federal matching funds for smart grid investments by utilities. This latter provision provides the basis for funds allocated under the American Recovery and Reinvestment Act in 2009.

Congress continues to consider new legislation to address cyber security concerns, privacy and data access for consumers, and other policies to accelerate investments in the future grid. In the next year, Congress is expected to launch a bipartisan caucus specifically focused on the future grid as well as to introduce new comprehensive grid legislation.

CONDITION AND REACH OF EXISTING INFRASTRUCTURE

The electrical grid connects approximately 144 million end-use customers with about 5,800 major power plants and includes over 450,000 miles of high voltage transmission lines [40]. In recent decades, the majority of transmission investment has been directed toward constructing new facilities to meet customer load demands. Meanwhile, relatively little has been invested in refurbishing existing facilities. This has resulted in much of the current power system infrastructure, whether generation, transmission, or distribution equipment, becoming outdated and in need of refurbishment, replacement, or upgrades in order to comply with new standards and to meet demand [3]. Nearly 70% of the grid's transmission lines and power transformers are now over 25 years old and the average age of power plants is over 30 years [40]. Some transmission and distribution components are over 80 years old. In the latter half of the upcoming 10-year period, a number of nuclear units are expected to undergo refurbishment or retirement. Many coal units will cease burning coal by 2014, with conversion to other fuels being considered as just one of several options [3].

Updating the existing infrastructure will present many challenges such as the availability of spare parts, the obsolescence of older equipment, the ability to maintain equipment due to outage scheduling restrictions, and the aging of the work force and resulting lost knowledge due to personnel retirements. Although many companies have sustainment programs in place for asset renewal, NERC asserts that it is the overall scope of the problem that presents the greatest challenge [3].

These updates will become more and more necessary as the age of infrastructure begins to show. The grid resiliency report entitled *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages* issued by the Executive Office of the President in August of 2013 states the following:

"The age of the grid's components has contributed to an increased incidence of weather-related power outages. For example, the response time of grid operators to mechanical failures is constrained by a lack of automated sensors. Older transmission lines dissipate more energy than new ones, constraining supply during periods of high energy demand. And, grid deterioration increases the system's vulnerability to severe weather given that the majority of the grid exists above ground" [40].

The Federal government has allocated billions of dollars to replace, expand, and refine grid infrastructure. The American Recovery and Reinvestment Act of 2009 allocated $4.5 billion for investments in modern grid technology. Smart grid technology utilizes remote control and automation to better monitor and operate the grid. Between June 2011 and February 2013, Recovery Act funds have been used to deploy 343 advanced grid sensors, upgrade 3,000 distribution circuits with digital technology, install 6.2 million smart meters, and invest in 16 energy storage projects. These investments have contributed to significant increases in grid resilience, efficiency, and reliability [40].

UP AND COMING TECHNOLOGIES

New companies are emerging frequently that are focused on providing new energy products to consumers. Companies like Home Depot, Lowes and Best Buy are focused on relatively inexpensive products that integrate energy management devices with other home automation products. Other companies are focused on commercial scale energy storage, fuel cells, etc. with an emphasis on convenience and security. While there will be winners and losers in this emerging market, it is clear that innovation is just beginning and companies and investors will sort out the market over the next decade or so resulting in winners and losers.

Microgrids

North America is the leading microgrid market, featuring 63% (992 MW) of the total worldwide installed microgrid capacity of 1,581 MW. This worldwide capacity is expected to increase to over 9,100 MW by 2020 with North America's share of this capacity expected to grow to almost 6,000 MW. Worldwide annual revenue from microgrids is expected to reach between US$30 million and US$60 million by 2020 [41].

The United States Department of Defense, as the single largest energy consumer in the world, is a crucial driver of microgrid development owing to the extreme sensitivity to T&D disruptions at their various bases around the world. Roughly two dozen facilities across all branches of the military are engaged in some form of microgrid implementation, often including the integration of renewable energy generation such as wind or solar [42].

Beyond the United States Department of Defense, public investment has come from various state and Federal including the U.S. Department of Energy, the Federal Emergency Management Agency, and the California Energy Commission. Some of the larger projects are occurring at the University of California, San Diego; in Salem, Oregon; and in Bridgeport, Connecticut. Islanding, EV integration, environmental disaster response, and distributed renewable energy generation management represent the focus of most of these projects.

Managing microgrid integration is an important aspect of grid evolution, both because this integration requires careful planning, and because this is a crucial element in solving current grid issues such as distributed renewable energy generation and disaster response.

Smart Cities

The term "smart city" currently has a number of different connotations depending on where and how the term is specified. For some cities, this is as simple as smart street lighting; for others, it refers to a highly integrated sensor network that provides real-time information regarding city service usage such as beaches, libraries, and parking. European cities such as Málaga [43] and Eindhoven [44] fall into the former category, while cities such as Santander [45] exemplify the latter concept. Generally, the term refers to the real-time creation and consumption of data streams in order to provide an adaptive or informed response to a citizen need or demand. Planning organizations are just starting to design smart cities, making it a clear priority looking forward and already impacting energy consumption data availability in many cities.

The amount of data being created and collected by municipalities and utilities is growing rapidly; by some estimates it is expected to double every two years until 2020 [46]. This data will, largely, be generated by vast automated sensor networks. This “Internet of Things” is expected to generate an estimated 40 trillion gigabytes of data [46]. Leveraging this data will be fundamental for municipalities to understand, because it is one of the basic components of the value architecture of future smart cities. Without understanding what is being measured and what that measurement says, municipalities and utility operators run the risk of being drowned by a metaphorical tsunami of unintelligible data points and statistics, or, worse yet, drawing the wrong conclusions by using answers to questions they did not want to ask [47]. Figure 14 provides a schematic representation of this smart city value architecture. It shows high-level characteristics as well as more specific features, components, and desired outcomes.

Moving forward, grid stakeholders need to be both intelligent providers and consumers of smart city data and services. This means planning grid development in conjunction with local and regional planning authorities in order to maximize participation in smart cities.

Figure 14. Smart City of the Future Value Architecture [46]

While still in their infancy, these kinds of plans represent the next evolution of large scale city planning, and have many details to work out (privacy concerns, etc.).

Demand Side Components

At present residential and commercial buildings represent 74% of the U.S. electricity consumption, and this figure is forecasted to grow a few percentage points by 2030 [48]. Some of the end-use consumption is from lighting, PCs, water heating, refrigeration, cooking, and HVACs. Lighting in particular has undergone a dramatic change in recent years as described below. In addition, low-cost, high-power computing has created opportunities for network-connected smart appliances with alert and remote control features for residential use. Commercial and industrial organizations are often looking to reduce bottom line operational costs through operational efficiency improvements. As a result, improvements in the end-use components have the potential to significantly affect how electricity is consumed.

Light Emitting Diode (LED) Lighting

Both residential and commercial consumers are making the switch to LED lights. In 2009, fewer than 400,000 LED lights were deployed across the U.S., but by 2013, deployment had grown to nearly 20 million LED lights. Although LEDs cost more up front, they also last as much as 25 times longer than the traditional incandescent light bulb. In 2012 some LED lighting products cost $50 a piece, but many of today's LEDs cost less than $15 [19].

Additionally, the consumer gains quite a bit from a LED lighting product's efficiency. Consider that a standard 60-Watt incandescent light bulb can be replaced by a ~9 Watt LED light that is 84% more efficient and with much less wasted heat. With the LED lasting over two decades, consumers could save over $140 for every incandescent bulb swapped for an LED replacement. DOE's Office of Energy Efficiency and Renewable Energy projects that by 2030 LED lighting will save Americans over $30 billion a year in electricity costs and cut America's energy consumption for lighting in half [19].

This transition in lighting impacts not only utilities' revenues but also their operating costs. Incandescent bulbs have a power factor (PF) of about 1, which means the actual power consumed (in Watts) and the apparent power (in volt-amperes) are equal. However, Energy Star has a minimum PF of 0.70 for LED lights greater than 5-Watts and no minimum PF for LED lights less than 5-Watts [49]. This means a 10-Watt LED with a PF of 0.7 pays for 10 Watts, but the utility would have to generate 1.4 times that power in volt-amps to run that light and pay for the additional generation. At the individual bulb level this is not significant but as LED lighting products gain more market share, the aggregate additional power needs will become an important consideration for utilities [50].

Residential

New refrigerators, dishwashers, washers, dryers, thermostats, carbon monoxide detectors, and smoke detectors are being sold with embedded computers capable of providing consumers monitoring, user habit learning, customizability, remote notification, and 24/7 remote control. Appliances such as washing machines and dishwashers can be programmed to operate during times convenient for the consumer or during the evening to minimize the noise disturbance from the operation. In the future, these appliances could be configured to respond to demand response signals or time differentiated rates to maximize savings for the customer, to modify peak demand, and in general to help improve grid operations. These appliances only represent a tiny fraction of the market today, but they are expected to become increasingly mainstream in market penetration through the 2010s and could reach up to US$35 million in sales by 2020.

Commercial and Industrial

Building energy demand can be broadly divided into lighting, general heating and cooling, and plug load, and it is a major cost component of any business operation. By implementing smart efficiency measures, such as those listed in Table 6, it is estimated that by 2035 the annual savings for the commercial sector from these technologies could reach US$30 billion to US$60 billion [51]. Similarly, for the industrial sector, annual savings by 2035 could range from US$8 billion to US$25 billion [51]. This expected improved building efficiency could help reduce electricity demand growth as the technologies become more widely deployed and even newer technologies are developed. These technologies will increasingly allow buildings to respond in near real-time to grid conditions such as voltage and frequency levels.

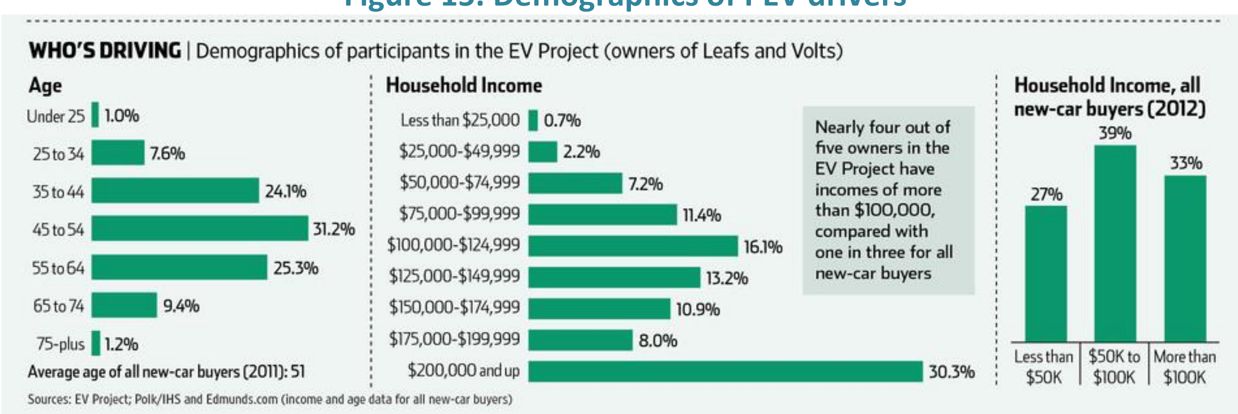
Table 6 - Intelligent Energy Measures for Commercial Sector [51]

Measure	Savings Range	Estimated Applicability
Smart Building Components	5%-20%	10%
Smart Lighting	0%-75%	35%
Smart HVAC Components	15%	10%-15%
Advanced Building Mgmt. Systems (BMS)	10%-30%	10%-20%
Smart Grid	10%	10%
User Interfaces	10%-20%	10%
Office Equipment and Cloud Computing	2%-50%	50%
Refrigeration Energy Management	30%	30%
Smart Fume Hoods	10%-30%	15%
Miscellaneous	20%-50%	2%

Electric Vehicles

Today's EV purchasers today are primarily city dwellers in places such as Lost Angeles, San Francisco, and Seattle, as well as New York, and Atlanta. The largest group of purchasers tends to be between the ages of 45 – 54 with household incomes greater than $100,000. EV drivers typically drive 9,000 miles per year as compared to 13,500 miles per year for all cars in the United States [52]. Figure 15 provides a demographic snapshot of who drives EVs and includes information on age and household income. It also compares this to the 2012 household income of all new-car buyers.

Figure 15. Demographics of PEV drivers



Despite this situation, there are several factors at play helping to increase the general market penetration of EVs, such as:

- President Obama's launch of the EV Everywhere Grand Challenge to make the cost of plug-in EVs on part with gasoline-powered vehicles by 2022;
- Nearly 50% drop in the cost of EV batteries in the past 4 years through high volume production [53];
- DOE's efforts with industry and academia to double the battery pack energy density [53]; and
- State support, in particular, 8 states (California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont) have pledged to adopt measures to make it easier to own an EV. Collectively they represent nearly one-quarter of America's auto market. Their goal is to achieve sales of at least zero-emissions 3.3 million vehicles by 2025. This would represent 25% of the light duty vehicle (LDV) annual sales.

Other factors positively influencing EV market share are purchasing incentives such as the Federal government tax credit up to $7,500 and state government incentives such as tax credits and rebates [54]. Lastly, there is the large difference fueling costs between EVs and conventional gasoline-powered vehicles. Nationally, EV fueling costs are about three times less than for vehicles running on gasoline.

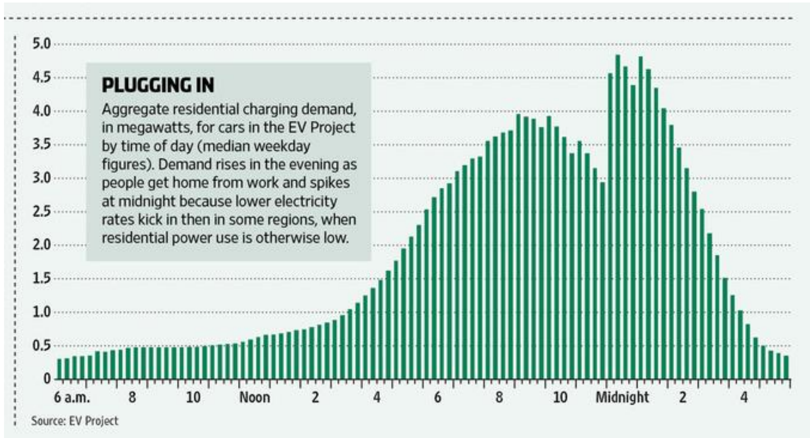
"In March 2012, President Obama announced the *EV Everywhere Grand Challenge*—to produce plug-in electric vehicles (PEVs) as affordable and convenient for the American family as gasoline-powered vehicles by 2022."[1]

Together, all of these factors are aligned with promoting and expanding EV market share. With this increased market penetration, though, will come significantly increased transportation sector demands for electricity.

Industry has been working tirelessly installing charging stations nationwide. As of June 2013, there were over 18,000 charging stations (both public and private) across the U.S. with approximately one dozen states (MA, NY, NC, TN, FL, TX, MI, IL, OR, WA, CA, and AZ) representing the majority of all installations [55]. In support of the President's EV Everywhere Challenge, DOE has launched the Workplace Charging Challenge aimed at increasing by tenfold over the next five years the number of U.S. employers offering charging installations [56].

Already there are several neighborhoods with high EV concentration. Pecan Street Research (PSR) Analytics analyzed over 2,500 vehicle charge events between June 1, 2013 and August 31, 2013 in a randomly selected subset of 30 homes in Austin, Texas. It found that charging behavior is more diverse than predicted and thus representing a much more manageable energy load [57]. However, how charging will impact the grid still remains to be seen. Today a majority of residential charging is done with Level 1 and Level 2 chargers. In the State of Washington, some of the 14 DC quick chargers on the West Coast Green Highway were used ten times more often than others [58]. In 20 years, technological advancements could make these quick chargers, wireless charging, or some other charging method common in the home. With states supporting a larger number of EVs in the market place, utilities will need to evaluate their distribution systems against these possible demand scenarios. Figure 16 shows aggregate residential charging demand (in MW) over the course of a typical day.

Figure 16. Residential Demand in High PEV Penetration Neighborhood



Smart grid projects/technologies

The American Recovery and Reinvestment Act of 2009 tasked the Department of Energy (DOE) with distributing over $4 billion in funding to smart grid projects across the country. This 8-year program is now entering its 6th year and has the potential to drastically change the power grid landscape of the United States. The two largest initiatives are the Smart Grid Investment Grant (SGIG) program and the Smart Grid Demonstration Program (SGDP). DOE's Office of Electricity Delivery and Energy Reliability (OE) is responsible for managing these five-year programs [59].

The first of these large initiatives, SGIG, focuses on deploying existing smart grid technologies, tools, and techniques to improve grid performance. Meanwhile, the other large initiative, SGDP, explores advanced smart grid and energy storage systems and evaluates performance for future applications. These projects are focused on regional demonstration projects and energy storage projects. For information about individual smart grid projects under the American Recovery and Reinvestment Act of 2009 visit http://www.smartgrid.gov/recovery_act/project_information.

The impact of these investments is still being analyzed in most cases, but the benefits are clear. Based on the results of these projects, the industry will innovate new and better solutions and fine tune the design and implementation for future projects to maximize the benefits.

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APPENDIX A - KEY FINDINGS FROM NERC 2012 LONG-TERM RELIABILITY ASSESSMENT

Significant Fossil-Fired Generator Retirements Over Next Five Years

Due largely to the unique confluence of final and potential environmental regulations, low natural gas prices, and other economic factors, about 71 GW of fossil-fired generation is projected to retire by 2022, with over 90 percent retiring by 2017. With the exception of the Electric Reliability Council of Texas (ERCOT), the retirement of this capacity does not pose significant resource adequacy concerns. Reserve Margins are likely to be reduced, but to levels that are still above targets. However, retirements over the next three to four years may raise issues related to system stability and the need for transmission enhancements, which if not addressed could cause reliability concerns in some areas.

Increased Risk of Capacity Deficiencies in ERCOT as Planning Reserve Margins Projected to Fall Below Targets

Starting as early as next year, the ERCOT Planning Reserve Margin is anticipated to be 13.4 percent, which is below the NERC Reference Margin Level and ERCOT planning target of 13.75 percent. At these levels, the risk of insufficient generation resources to meet peak demand increases beyond reliability targets.

Resources Sufficient to Meet Reliability Targets in Most Areas

For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability through the long-term horizon. However, there are significant challenges facing the electric industry that may shift industry projections, adding considerable uncertainty to the long term assessment. Future uncertainties include electricity market changes, fuel-prices (natural gas, in particular), potential environmental regulations, and renewable portfolio standards.

Increased Dependence on Natural Gas for Electricity Generation

Increased dependence on natural gas for electricity in some areas has increased the need for all gas users, electric system planners and operators, and policy makers to focus more sharply on the interaction between the electric and gas industries. The adoption of highly efficient combined-cycle technology by the electric power industry and the emergence of shale gas have altered the relative economics of gas-fired generation. As a result, the dependence on natural gas by the electric power sector has increased significantly. Trends in fuel-mix changes highlighted in this assessment identify gas-fired generation as the primary choice for new capacity with almost 100 GW of Planned and Conceptual capacity expected over the next 10 years, which represents almost half of all new generation capacity.

Long-Term Generator Maintenance Outages for Environmental Retrofits

A significant generation retrofit effort is expected over the next 10 years in order to comply with Federal and state- level environmental regulations. A majority of environmental controls are expected to be put in place to meet air regulations by April 2016. In total, 339 unit-level retrofits on fossil-fired generation will be needed, totaling about 160 GW. However, there is still significant uncertainty in the forecasted values as maintenance schedules have not yet been fully evaluated by all areas.

Renewable Resource Additions Introduce New Planning and Operational Challenges

Renewable resources are growing in importance in many areas of North America as the number of new facilities continues to increase. The share of capacity from renewable resources will continue to grow, especially as significant additions are projected for both wind and solar throughout North America. In 2012, renewable generation, including hydro, made up 15.6 percent of all on-peak capacity resources and is expected to reach almost 17 percent in 2022. Contributing to this growth is approximately 20 GW of on-peak Future-Planned capacity and an additional 21.5 GW of on-peak Conceptual capacity. It is vital that these variable resources are integrated reliably and in a way that supports the continued performance of the BPS and addresses both planning and operational challenges.

Transmission Growth to Accommodate New and Distant Resources

As recent as five years ago, transmission was being constructed at a rate of about 1,000 circuit miles per year. In the last five years, over 2,300 circuit miles were constructed per year, more than doubling actual builds in the previous five years. With the current plans in place, that rate is expected to increase to 3,600 miles per year over the next five years. NERC-wide, almost a quarter of new transmission is specifically linked to the integration of renewable generation.

Increases in Demand-Side Management Help Offset Future Resource Needs

All areas are projecting at least some increased availability of Demand-Side Management (DSM) over the next 10 years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in day-ahead or real-time time operations. NERC-wide, DSM is projected to total roughly 80,000 MW by 2022 (or about 7 percent of the on-peak resource portfolio), offsetting approximately six years of peak demand growth. However, unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of DSM involve greater forecasting uncertainty—particularly with Demand Response resources.